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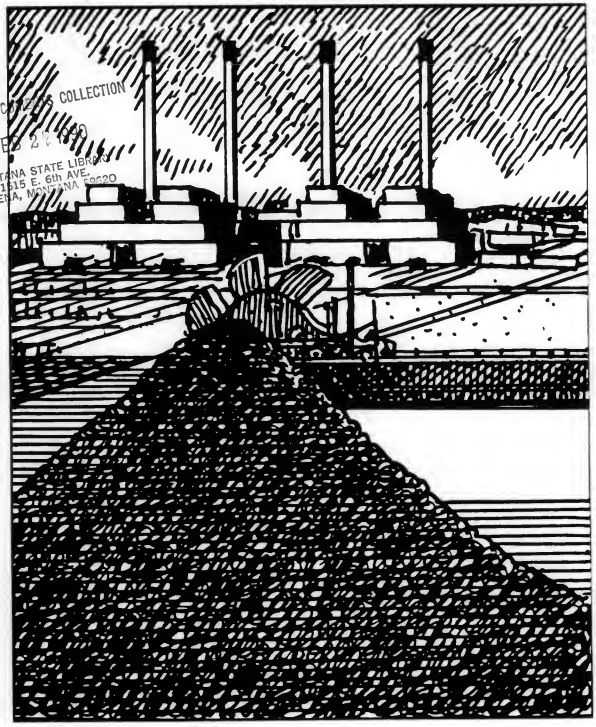
COAL-FIRED GENERATING RESOURCES

89-44



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November 2, 1989

To Interested Parties:

The Council staff is circulating the following issue paper entitled, **"Coal-fired Generating Resources"** (publication #89-44).

This activity is part of the process to produce a new draft Northwest Power Plan by mid-1990. As part of this effort, all potential electricity resources are being reviewed and analyzed. At this point, the Council has taken no position on the issues and analysis discussed in this paper. The purpose of the staff paper is to provoke discussion and solicit input. Information raised in the paper will help the Council make future decisions about resources that will be included in the plan's resource portfolio.

In the previous two power plans, coal-fired electric plants have been the resource of margin in the resource portfolio; that is, the last resource the region would turn to in the event of high growth. This paper looks at both new developments that could constrain the use of coal and new technologies that might offset some of those limitations. While the Council welcomes all comments, it is particularly interested in responses in four broad areas. These four areas are posed as questions on page two of the issue paper.

The Council will make no decisions on this issue until it has evaluated all comment received on a timely basis. **Deadline for comment on this paper is 5 p.m., Friday, December 15, 1989. Oral testimony will be taken at the Council's meeting on December 13-14 in Portland, Oregon.** Please mark comments with the name or number of the issue paper you are addressing.

Sincerely,

Dulcy Mahar, Director
Public Involvement

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November 1, 1989

Staff Issue Paper 89-44

COAL-FIRED GENERATING RESOURCES

BACKGROUND

In the 1983 and 1986 power plans, coal-fired generating resources were the marginal (last) generating resource in the Council's resource portfolio. As such, coal-fired technologies represented the highest-cost resource in the portfolio and, as a result, established an economic target for all other conservation and generating resources to beat. In estimating the cost of coal-fired generating resources in the past power plans, the Council assumed the use of large pulverized coal-fired steam electric power plants, providing about 600 megawatts of capacity and 450 average megawatts of energy, located in eastern Washington or Oregon.

It was unlikely that many coal-fired resources would be developed over the next 20 years due to two factors. First, since coal-fired resources were the most expensive resources in the plan, they only met the needs of the highest load-growth scenarios. Because high load growth is unlikely, it was likewise unlikely that the region would have to build those resources. Second, the Council used the coal resources as an economic benchmark against which other resources could compete for a place in the region's energy future. Through schemes such as bidding or avoided cost pricing, the Council argued that a wide variety of more flexible (smaller and shorter lead time) resources would be developed in lieu of many coal-fired power plants in the plan. Because it is impossible to fully know the wide variety of emerging resources that will be available, the Council chose to include coal-fired power plants as a "placeholder" to encourage alternative dispersed resource development from a spectrum of resource alternatives.

Also in past power plans, the Council has assumed that there is essentially an unlimited amount of coal-fired generating capability available to the region over the next 20 years. This assumption has been challenged. While it is possible that large amounts of coal can be added strictly from a technical and theoretical perspective, it is unlikely that the region's technical, economic and environmental infrastructures could support unlimited development of coal-fired resources. For this reason, this issue paper evaluates coal-fired generating technologies that could be available to the region over the next 20 years and establishes a scenario for evaluating such technologies for the 1990 Power Plan.

To shorten the discussion incorporated in this issue paper, the Council proposes to use technical and economic assumptions surrounding coal-fired resources adopted

last spring in the 1989 Supplement to the 1986 Power Plan. For readers interested in reviewing these technical assumptions, they are incorporated in Volume I, Chapter 4, beginning on page 57, and Volume II, Chapter 4, beginning on page 4-47. Since these estimates appear to be currently valid, the Council does not propose to review them again. However, this paper makes several adjustments to the current estimates of coal-fired resource costs and availability. To develop a credible coal-based scenario, costs for additional rail transportation, environmental control technology and electric transmission were added to the costs of coal and the estimates of the costs of performance of coal-fired generating technologies included in the 1989 supplement. Anyone with new or better information than in the 1989 supplement and the information contained in this issue paper should comment at this time.

Deadline for comment is 5 p.m., Friday, December 15, 1989. Oral testimony will be taken at the Council's November 8-9, 1989 meeting in Helena, Montana, and at the December 13-14, 1989 meeting in Portland, Oregon. To help us record and circulate your comments quickly and accurately, please mark your comments with the issue paper title or publication number.

ISSUES FOR THE 1990 POWER PLAN

In determining the role for fossil-fired generating resources in the 1990 Power Plan, the Council has four primary questions on which this issue paper seeks public comment:

1. Are there technical, environmental or policy limits to the amount of coal technologies that should be included in the region's plan?

2. Should there be a variety of coal technologies in the Council's portfolio in order to diversify the risk posed by coal-fired technologies?

3. Do the costs of coal technologies increase as substantial amounts of coal-fired resources are added to the region's power system?

4. Are the estimates of transportation, environmental controls and transmission costs accurate, and is the proposed coal scenario realistic?

In addressing these four questions, the Council needs to evaluate a variety of environmental, technical and economic constraints to developing coal-fired technologies. The remainder of this issue paper will discuss some of these constraints and suggest a possible coal-fired generating resource scenario and supply function. This effort aims to establish a consensus on the appropriate role of coal-fired technologies, a supply function for evaluating coal technologies, limits on the types of coal technologies called upon in the region's plan, and a reasonable scenario for how coal-fired resources might develop over the next 20 years is proposed.

LIMITS TO THE DEVELOPMENT OF COAL-FIRED GENERATION

Future use of coal-fired generating technologies presents significant questions concerning air quality impacts, site availability, coal transportation and electric power transmission. Figure 1 illustrates the variety of coal sources, transportation

options, generating sites, generating technology, environmental controls and electrical transmission available to the region.

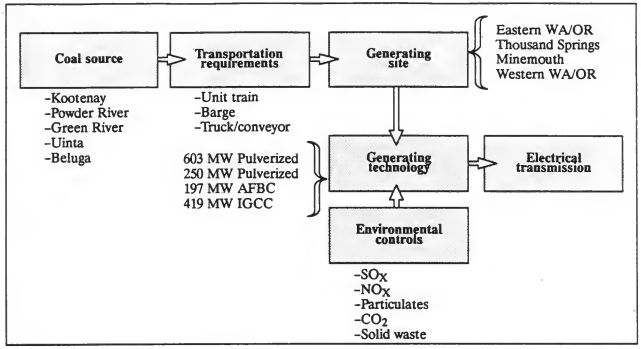

Figure 1
Coal-Fired Generation Scenarios

AIR QUALITY EFFECTS

Coal combustion products affect air quality and may result in widespread secondary impacts to atmospheric, hydrological and ecological systems. Among the combustion products of greatest concern are oxides of sulfur (SO_x), oxides of nitrogen (NO_x), carbon dioxide and particulates. Systems for control of NO_x, SO_x and particulates are available and in place on power plants constructed following the implementation of the Clean Air Act. No system for control of carbon dioxide is in current use on power plants, and significant technical development would be required in order to remove carbon dioxide from power plant effluents. At full capacity a large coal-fired power plant emits about 2,800,000 pounds of CO_2 per hour, or about 35 million cubic feet. It is hard to imagine a process for handling the massive amounts of exhaust gases from a coal plant and scrubbing the major portion of the CO_2 released from coal combustion.

To evaluate additional coal-fired generating technologies, one possible scenario is that a significant increase in coal generation might require no net increase in SO_x or NO_x. This strategy can be called the "zero increment" approach to developing coal-fired generating technologies. If applied, the technique would involve the purchase of emission offsets from existing coal-fired generating resources (or possibly other sources) in the region to support developing new coal-fired generating technologies. This strategy would not increase the rate at which SO_x and NO_x were being disbursed to the region's environment. The region currently has installed about 3,154 average megawatts of coal-fired generating technologies,

much without scrubbers. The addition of scrubbers to these units would reduce the SO_x emissions by about 70 percent. This means that if all the region's coal-fired generating resources were retrofitted with scrubbers removing 70 percent of the SO_x emissions, about 7,000 megawatts of new power plants could be built with 70 percent SO_x removal while maintaining the same overall level of SO_x emissions the region currently experiences. Additional new megawattage of coal-fired plants could be built under a zero increment approach if more stringent scrubbing technology (e.g., 90 percent SO_x removal) were employed.

SITE AVAILABILITY

The maximum upper limit of sites for coal-fired generating technologies in the region is substantially above what could be developed reasonably over the next 20 years. While factors such as the ability of the airshed to absorb atmospheric discharges from the plants and availability of water for cooling interact with the proximity to the transmission grid and the proximity to rail transportation systems, the overall availability of sites within the region to support additional coal-fired generating technologies is not likely to be a constraint in the next power plan.

There are several general locations for additional coal-fired resources within and near the region. First are sites that exist in eastern Washington and Oregon. Currently, Washington Water Power Company has licenses for a two-unit coal-fired power plant at Creston, Washington. Though the licenses are for a four-unit plant of 2,032 megawatt total capacity, it is likely that additional air quality constraints near the site would limit new capacity at the Creston site to about 1,000 megawatts if conventional pulverized coal-fired plants with flue gas desulfurization are used. In addition, licenses are about to lapse on an additional unit at the Boardman site in Oregon. Ultimately, there are several sites available in eastern Washington and Oregon that could provide adequate access to water, rail and transmission.

In lieu of transporting coal by train, the possibility exists to construct coal-fired power plants at coal mines and transport the electricity via additional high voltage transmission. These minemouth power plants could be located at a variety of sites near coal fields in Montana, Wyoming, Utah, British Columbia or Alberta. However, with additional transmission comes increasing impacts on land use, aesthetic and visual values, and concerns regarding the health effects of electromagnetic fields.

There is currently a proposal to develop a coal-fired power complex in northern Nevada, near Thousand Springs. This site reportedly is licensed for eight 250 megawatt coal-fired power plants to be developed by Sierra Pacific resources. The company plans to market the output of these plants to customers throughout the West. Additional transmission capability would be required for energy from the Thousand Springs power plant to be available to the region.

Finally, there is the possibility of developing additional coal-fired generating technology in western Washington or Oregon. While adding additional generation into the major load centers of the Northwest has advantages in terms of avoiding additional electric power transmission, it also brings disadvantages of probable air quality problems and additional rail haul distances. For this reason, it is likely that if additional coal-fired generating resources were built in western Oregon or

Washington there would be significantly increased requirements for environmental controls and additional costs for coal transportation systems to support the plant.

TRANSPORTATION SYSTEMS

Because central station coal-fired plants require large volumes of coal, rail or water transportation routes must be available to meet the needs of each plant. In the case of rail transportation, the ability of the current rail system to safely and reliably deliver coal in the amounts required by higher load-growth cases is not entirely clear. The representative 1,200 megawatt two unit coal-fired power complex would require about 130 to 190 rail cars of coal per day in full operation. The existing rail transportation routes from the eastern coal fields could limit the ultimate amount of coal that can be transported to Washington and Oregon. It is difficult to analyze exactly how much coal could be transported over the existing rail system due to the interaction between unit coal trains and other rail traffic that would use the same lines. To evaluate the impact of this factor on the cost-effectiveness of coal plants, some scenarios may require building additional track within existing right-of-ways.

ALTERNATIVE GENERATING TECHNOLOGIES

The major coal-fired generating technologies fall into four categories. First is conventional pulverized coal-fired power plants. These are available in a variety of sizes. However, for the Council's studies, we have primarily relied on two plant sizes: a large plant at 603 megawatts of capacity and a smaller plant at 250 megawatts of capacity. While the smaller plant offers more flexibility and shorter lead times, the larger plant experiences some economies of scale that lead to lower capital cost.

A second category of coal-fired power plant, gaining prominence throughout the world, relies on air injection to burn coarsely ground coal in a bed of limestone particles. The limestone removes sulfur from the coal, thus reducing or eliminating the need for flu-gas desulfurization. In atmospheric fluidized bed combustion (AFBC), the fluidized bed operates near atmospheric pressures. The AFBC plant's characteristics included in the supplement are based on AFBC designs recently prepared for the Electric Power Research Institute by Bechtel. In this issue paper, the primary AFBC design that is evaluated is a single 200-megawatt plant that is similar to recent AFBC demonstration projects.

Pressurized fluidized bed (PFBC) plants are a further refinement of AFBC technology. PFBC plants operate at elevated pressures so that the exhaust gases can be passed through a gas turbine thus further increasing the overall plant efficiency.

The third general classification of coal-fired technologies involves gasification of coal and using the gas to power conventional combustion-turbine combined-cycle power plants. The gas turbines directly run electric power generators, while the exhaust heat from the turbines is used to create steam in boilers and operate a secondary steam cycle. This significantly improves the overall thermal efficiency of the plant. These plants feature a high degree of modularity, improved control of atmospheric emissions and high energy-conversion efficiencies. A prototype coal-gasification combined-cycle power plant was demonstrated at the 100-megawatt Cool Water plant in California.

In this issue paper, a coal-gasification combined-cycle power plant is assumed to involve a four-unit complex of approximately 420 megawatts per unit. Obviously, coal-gasification combined-cycle power plants can be developed in phases. The first phase would involve installing simple cycle combustion turbines, relying on natural gas or oil as a fuel. Phase two would add a steam cycle, using the exhaust heat from the combustion turbines, thus improving the overall thermal efficiency, but continuing to fire the plant on natural gas or oil. Phase three would involve installation of a coal gasification unit, which could then be used to fire the power plants via gasified coal. The gasification section would include coal handling, storage and preparation facilities, an oxygen plant, Shell gasifiers, gas clean-up and sulfur recovery facilities. Because of the characteristics of the gasification process, there are opportunities to significantly reduce sulfur emissions.

The last category of coal-fired technologies is magnetohydrodynamics (MHD). MHD is a process for converting heat energy directly into electricity. MHD is characterized by high combustion temperatures, combined-cycle operation and direct conversion of thermal energy to electric energy. MHD technologies can potentially provide significant improvements in energy conversion efficiency. At the same time, it is possible that this technology could significantly improve the ability to control atmospheric emissions. This technology is still undergoing development. Significant improvements, both in the reliability and the cost of MHD units, are necessary before this technology can reliably be counted upon in the Council's plan.

POSSIBLE COAL DEVELOPMENT SCENARIOS

A coal-fired generation supply curve should anticipate a most likely scenario for developing additional coal-fired generating resources when needed. In this discussion, the Council is not advocating the use of any particulate sites. Specific sites are only assumed for the purpose of providing specific cost estimates. Significant analysis, discussion and thought would be necessary to finally select the desired sites and technologies. Table 1 shows a summary of a scenario that is used to develop one of many possible coal-fired generation supply curves. In this scenario, coal is developed in five distinct stages.

The various stages in this scenario for coal-fired resources begin with cost and availability assumptions from the 1989 supplement. These initial assumptions are modified to incorporate additional rail costs, environmental offsets and transmission costs as appropriate for each stage shown in Table 1. The key assumptions used are shown in Table 2. The Council especially requests comments on the validity of these cost assumptions.

Table 1
Coal-Fired Supply Curve

Coal Source	New Rail or Upgrade Required	Power Plant Site	Additional ECT	New Transmission	Generating Technology
Kootenay	Yes	Creston	No	Yes	2 x 603 pulverized
Powder/ Green River	No	Minemouth	"Zero" Inc.	Yes	8 x 197 AFBC[1]
Powder River	No	Boardman	"Zero" Inc.	No	2 x 603 Pulverized
Uinta	No	Thousand Springs	"Zero" Inc.	Yes	4 x 250 Pulverized
Kootenay	Yes	Western OR/WA	"Zero" Inc.	No	4 x 419 IGCC[2]

Table 2
Fossil-Fired Resource Assumptions

COAL COSTS	FOB Mine $ MM Btu
Centralia	1.67
Green River	.86
East Kootenay	.81
Powder River	.25
Uinta	.61

RAIL SYSTEM EXPANSION COSTS	
Rolling stock–Unit train	$8.60/kW/year
Variable transportation costs	$0.32/MMBtu
Track upgrade	$1 million/mile
Fixed charge rate for track	15 percent/year
Increased rail capacity	2,000 megawatts

ADDITIONAL ENVIRONMENTAL CONTROL COSTS

Coal type	Scrubber costs $/MMBtu	Retro fit costs $/MMBtu
Centralia	.97	1.21
Green River	.56	.70
East Kootenay	.51	.63
Powder River	.42	.53
Uinta	.51	.63

TRANSMISSION SYSTEM UPGRADE COSTS

Line size	Transfer capacity	Cost/mile
2x230 kv	500 MW	$370,000
1x500 kv	1,000 MW	$600,000
2x500 kv	2,400 MW	$880,000

1./ Atmospheric fluidized bed combustion.

2./ Integrated gasification combined cycle.

Stage 1 involves developing two 605-megawatt conventional pulverized coal plants at the existing Creston site. It is assumed that these plants are fired by East Kootenai coal from British Columbia since this represents the most economic coal for delivery to eastern Washington at this time. Because both sites are currently licensed, no additional environmental control technology over what was required to obtain the site license is assumed. Because the sites are in eastern Washington and near transmission, only a small amount of additional transmission is required to integrate the plants into the grid. Also a small amount of existing rail lines need to be upgraded.

Table 3 shows the technical and economic assumptions used to analyze the cost of constructing and operating two 603-megawatt units at the Creston site. This cost analysis provides for the costs and source of coal used to fire the plant, transportation costs used to transport the coal to the plant, generation costs involved in constructing and operating the plant, additional environmental controls that might be required because of changes in coal characteristics, and costs of constructing an additional electric transmission if needed. A cost summary adding up all of the various cost components is shown at the bottom of the table with the estimated life-cycle cost in levelized nominal 1988 dollars. The analysis conducted for the first two coal-units at the Creston site estimated that they would have a levelized nominal cost in 1988 dollars of 8.45 cents per kilowatt-hour.

Because the region has not licensed additional coal units, the further development of a coal scenario assumes that additional environmental control technologies would have to be retrofit to existing power plants in the region. The goal of this retrofit would be to achieve an overall level of emissions that is a "zero increment" over what the region is currently experiencing. This strategy holds for the remainder of the power plants developed as a part of the supply curve. Under this scenario, the region maintains the current level of environmental impact from SO_x emissions.

Stage 2 would be to move the power plants toward the mines and rely on minemouth generation technology. By the time this strategy is implemented, it is expected that AFBC would be the technology of choice for a minemouth coal complex. Therefore, it is assumed that eight 197-megawatt AFBC minemouth power plants are developed near the Powder River Basin or the Green River Basin. Substantial amounts of electric power transmission are needed to move the power to the load centers in the western side of the region.

Table 4 illustrates the technical and economic assumptions that were used to evaluate eight 197-megawatt atmospheric fluidized bed combustion power plants located at coal mines in the Powder or Green River basins in Montana or Wyoming. For these studies, it was assumed that there would be the need to purchase additional environmental control technology on existing coal plants within the region to reduce the incremental emissions to zero net increase. This stage would also require the construction of 600 miles of new double-circuit 500 kV transmission lines in order to transmit the power produced by these power plants to the western side of the region. The estimated costs of energy from this strategy would be 8.82 cents per kilowatt-hour, which is nearly cost competitive with Stage 1.

Table 3
Fossil-Fired Resources Cost Analysis

Site	Creston	Energy per unit	422 average megawatts
Capacity	1,206 megawatts (2 units at 603 megawatts each)	Availability	70 percent

Coal Source and Cost	Coal source	Kootenay
	Mine-mouth cost	$0.81/MMBtu
	Delivered cost	$1.13/MMBtu
Transportation Costs	Rolling stock	$8.60/kW/year
	Variable transportation cost	$0.32/MMBtu
	Upgraded track	40 miles
	Upgraded track cost	$1 million/mile
	Fixed charge rate for track	15 percent
	Annual cost	$6 million/year
	Upgraded track cost/unit cap.	$4.98/kW/year
Generation Costs	Plant type	Two 605-megawatt pulverized coal plants
	Total capacity	1,206 megawatt capacity
	Energy output	844 average megawatts
	Capital cost	$1,245/kW
	Total construction cost	$1,501 million
	Fixed fuel cost	$8.60/kW/year
	Variable fuel cost	$1.13/MMBtu
	Fixed O&M cost	$25.48/kW/year
	Variable O&M cost	.19 cents/kWh
Additional Environmental Control Costs	Cost basis	Current license
	Cost increment for coal type	$5.99/kW/year
	Cost of 30% SO_x offset	None required
Long Distance Transmission	Type	Double circuit 500 kv
	Miles of transmission upgrade	83 miles
	Cost of transmission	$0.880 million/mile
	Transmission capacity	1,206 megawatt capacity
	Transmission cost/unit capacity	$60.56 per kilowatt
Total Cost Summary	Total capacity	1,206 megawatts
	Net energy	844 average megawatts
	Capital cost	$1,305.60/kilowatt
	Fixed fuel cost	$8.60/kW/year
	Fixed O&M cost	$31.47/kW/year
	Variable fuel cost	$1.13/MMBtu
	Variable O&M cost	.19 cents/kWh
	Levelized nominal cost 1988$	8.45 cents/kWh

Table 4
Fossil-Fired Resources Cost Analysis

Site	Mine-mouth Powder/Green River - AFBC	Energy per unit	149 average megawatts
Capacity	1,576 megawatts (8 units at 197 megawatts each)	Availability	76 percent

Coal Source and Cost	Coal source	Powder River
	Mine-mouth cost	$0.26/MMBtu
	Delivered cost	$0.26/MMBtu
Transportation Costs	Rolling stock	$0/kW/year
	Variable transportation cost	$0/MMBtu
	Upgraded track	0 miles
	Upgraded track cost	$1 million/mile
	Fixed charge rate for track	15 percent
	Annual cost	$0 million/year
	Heat rate	9,885 Btu/kWh
	Upgraded track cost/unit cap.	$0/MMBtu
Generation Costs	Total capacity	1,576 megawatt capacity
	Energy output	1,197 average megawatts
	Capital cost	$1,792/kW
	Total construction cost	$2,824 million
	Fixed fuel cost	$0/kW/year
	Variable fuel cost	$0.26/MMBtu
	Fixed O&M cost	$37.10/kW/year
	Variable O&M cost	.48 cents/kWh
Additional Environmental Control Costs	Cost basis	Zero increment
	Cost increment for coal type	$0/kW/year
	Cost of 30% SO_x offset	$23.034/kW/year
Long Distance Transmission	Type	Double circuit 500 kv
	Miles of transmission upgrade	600 miles
	Cost of transmission	$0.880 million/mile
	Transmission capacity	1,576 megawatt capacity
	Transmission cost/unit capacity	$335/kW
Total Cost Summary	Total capacity	1,576 megawatts
	Net energy	1,197.8 average megawatts
	Capital cost	$2,127/kilowatt
	Fixed fuel cost	$0/kW/year
	Fixed O&M cost	$60.13/kW/year
	Variable fuel cost	$.260/MMBtu
	Variable O&M cost	.48 cents/kWh
	Levelized nominal cost 1988$	8.82 cents/kWh

Stage 3 in coal-fired technology development involves installing two 603-megawatt pulverized coal plants at or near Boardman. These two units would be fired on Powder River Basin coal and would not involve developing additional rail lines or significant new electrical transmission.

Table 5 shows the technical and economic assumptions used to evaluate this stage of coal development. Since the next two coal units are assumed to be located at or near Boardman and fired by Powder River coal, it was assumed that existing rail-haul lines could supply the needs of an additional two units at the Boardman site. Also, because the Boardman site is near transmission, it was assumed that no additional transmission would be needed. However, consistent with the other stages, this stage will require an environmental offset to be purchased from existing coal-fired power plants in the region. The total cost of pursuing Stage 3 is estimated to cost 9.41 cents per kilowatt-hour on a levelized life-cycle cost basis.

Stage 4 in the development of coal-fired resources in the region assumes the purchase of energy from the Thousand Springs power plant site in Nevada. This power plant would be fired with Uinta Basin coal and would not require developing additional rail transport systems. But it would require developing additional electric power transmission lines to interconnect with the Pacific Northwest grid. Idaho Power Company is exploring whether to develop this integration as part of its current transmission system development and planning. In this analysis, it was assumed that 500 miles of additional double-circuit 500 kv transmission would be needed to transport power from Thousand Springs into the Pacific Northwest grid. Table 6 shows the economic assumptions used for this stage and the cost of pursuing Thousand Springs is estimated to be 10.76 cents per kilowatt-hour.

Stage 5 involves developing four 419-megawatt coal-gasification combined-cycle power plants on the western side of the region. This power plant complex could be located somewhere in western Washington or Oregon. Current gasification designs provide a high level of environmental control. Using typical coal gasification technologies, we assume that a smaller SO_x offset would be needed, since current emissions are designed for about 85 percent removal. This scenario would probably require developing additional rail transport capability. Therefore, we assumed that Kootenai coal would be transported via 600 miles of upgraded rail lines to western Oregon or Washington. This transportation expense and the added cost of a coal-gasification plant significantly adds to the overall cost of electric power delivered through this strategy. Table 7 illustrates the technical and economic assumptions used to analyze this stage of the coal development scenario. The cost of delivered energy using a coal-gasification combined-cycle power plant in western Washington and Oregon, including upgrades to the existing rail transportation system and purchase of an additional environmental increments from existing coal plants, is estimated at 11.08 cents per kilowatt-hour.

Table 5
Fossil-Fired Resources Cost Analysis

Site	Boardman	Energy per unit	422 average megawatts
Capacity	1,206 megawatts (2 units at 603 megawatts each)	Availability	70 percent

Coal Source and Cost	Coal source	Powder River
	Mine-mouth cost	$0.25/MMBtu
	Delivered cost	$1.49/MMBtu
Transportation Costs	Rolling stock	$8.60/kW/year
	Variable transportation cost	$1.24/MMBtu
	Upgraded track	0 miles
	Upgraded track cost	$1 million/mile
	Fixed charge rate for track	15 percent
	Annual cost	$0 million/year
	Heat rate	10,856 Btu/kWh
	Upgraded track cost	$0/MMBtu
Generation Costs	Plant type	Two 650-megawatt pulverized coal plants
	Total capacity	1,206 megawatt capacity
	Energy output	844 average megawatts
	Capital cost	$1,245/kW
	Total construction cost	$1,501 million
	Fixed fuel cost	$8.60/kW/year
	Variable fuel cost	$1.49/MMBtu
	Fixed O&M cost	$20.50/kW/year
	Variable O&M cost	.19 cents/kWh
Additional Environmental Control Costs	Cost basis	Zero increment
	Cost increment for coal type	$0/kW/year
	Cost of 30% SO_x offset	$23.30/kW/year
Long Distance Transmission	Type	Double circuit 500 kv
	Miles of transmission upgrade	0 miles
	Cost of transmission	$0.880 million/mile
	Transmission capacity	1,206 megawatt capacity
	Transmission cost/unit capacity	$0 per kilowatt
Total Cost Summary	Total capacity	1,206 megawatts
	Net energy	844.2 average megawatts
	Capital cost	$1,245/kilowatt
	Fixed fuel cost	$8.60/kW/year
	Fixed O&M cost	$43.80/kW/year
	Variable fuel cost	$1.49/MMBtu
	Variable O&M cost	.19 cents/kWh
	Levelized nominal cost 1988$	9.41 cents/kWh

Table 6
Fossil-Fired Resources Cost Analysis

Site	Thousand Springs	Energy per unit	180 average megawatts
Capacity	1,000 megawatts (4 units at 250 megawatts each)	Availability	72 percent

Coal Source and Cost	Coal source	Uinta
	Mine-mouth cost	$0.61/MMBtu
	Delivered cost	$1.07/MMBtu
Transportation Costs	Rolling stock	$8.60/kW/year
	Variable transportation cost	$0.46/MMBtu
	Upgraded track	0 miles
	Upgraded track cost	$1 million/mile
	Fixed charge rate for track	15 percent
	Annual cost	$0 million/year
	Upgraded track cost	$0/kW/year
Generation Costs	Plant type	Four 650-megawatt pulverized coal plants
	Total capacity	1,000 megawatt capacity
	Energy output	720 average megawatts
	Capital cost	$1,714/kW
	Total construction cost	$1,714 million
	Fixed fuel cost	$8.60/kW/year
	Variable fuel cost	$1.07/MMBtu
	Fixed O&M cost	$32.80/kW/year
	Variable O&M cost	.3 cents/kWh
Additional Environmental Control Costs	Cost basis	Zero increment
	Cost increment for coal type	$0/kW/year
	Cost of 30% SO_x offset	$24.29/kW/year
Long Distance Transmission	Type	Single circuit 500 kv
	Miles of transmission upgrade	500 miles
	Cost of transmission	$0.6 million/mile
	Transmission capacity	1,000 megawatt capacity
	Transmission cost/unit capacity	$300 per kilowatt
Total Cost Summary	Total capacity	1,000 megawatts
	Net energy	720 average megawatts
	Capital cost	$2,014/kilowatt
	Fixed fuel cost	$8.60/kW/year
	Fixed O&M cost	$57.09/kW/year
	Variable fuel cost	$1.07/MMBtu
	Variable O&M cost	.3 cents/kWh
	Levelized nominal cost 1988$	10.76 cents/kWh

Table 7
Fossil-Fired Resources Cost Analysis

Site	Western Washington/Oregon	Energy per unit	314 average megawatts
Capacity	1,676 megawatts (4 units at 419 megawatts each)	Availability	75 percent

Coal Source and Cost	Coal source	Kootenay
	Mine-mouth cost	$0.81/MMBtu
	Delivered cost	$1.34/MMBtu
Transportation Costs	Rolling stock	$8.60/kW/year
	Variable transportation cost	$0.53/MMBtu
	Upgraded track	600 miles
	Upgraded track cost	$1 million/mile
	Fixed charge rate for track	15 percent
	Annual cost	$90 million/year
	Upgraded track cost	$53.70/kW/year
Generation Costs	Plant type	Four 419-megawatt gasification combined-cycle
	Total capacity	1,676 megawatt capacity
	Energy output	1,257 average megawatts
	Capital cost	$1,820/kW
	Total construction cost	$3,050 million
	Fixed fuel cost	$8.60/kW/year
	Variable fuel cost	$1.34/MMBtu
	Fixed O&M cost	$114.92/kW/year
	Variable O&M cost	.08 cents/kWh
Additional Environmental Control Costs	Cost basis	Zero increment
	Cost increment for coal type	$0/kW/year
	Cost of 30% SO_x offset	$10.66/kW/year
Long Distance Transmission	Type	None
	Miles of transmission upgrade	0 miles
	Cost of transmission	$0.880 million/mile
	Transmission capacity	0 megawatt capacity
	Transmission cost/unit capacity	$0 per kilowatt
Total Cost Summary	Total capacity	1,676 megawatts
	Net energy	1,257 average megawatts
	Capital cost	$1,820/kilowatt
	Fixed fuel cost	$8.60/kW/year
	Fixed O&M cost	$125.58/kW/year
	Variable fuel cost	$1.34/MMBtu
	Variable O&M cost	.08 cents/kWh
	Levelized nominal cost 1988$	11.08 cents/kWh

As a result of analyzing these stages, Figure 2 illustrates a proposed coal supply function for the Council's planning. The Council is particularly interested in comments or observations about this or other strategies that could be used to develop coal resources and whether this level of development is possible given future environmental concerns that are likely to surround coal-fired development.

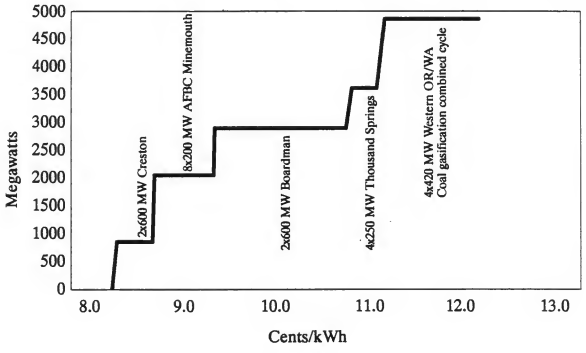

Figure 2
Coal Supply Curve

RISKS AND UNCERTAINTIES OF COAL-FIRED DEVELOPMENT

Coal, like all generating resources, brings with it substantial uncertainties concerning its ultimate development. First, in the area of environmental uncertainty, there is the opportunity for significantly tighter air-quality regulations. The recent presidential initiative concerning air quality and the likelihood that additional air-quality restrictions will develop as the country's air quality continues to diminish means that there will be significant uncertainty about the ultimate cost of delivering energy from coal-fired resources.

The issue of CO_2 is a very complex one. Current knowledge of the likely severity and timing of impacts on the global climate from additional CO_2 emissions is poorly understood. As a result, it is likely that over the lifetime of these power plants (40 years) there could be much stronger requirements to remove or reduce the amount of CO_2 emitted. Technologies for removing CO_2 do not exist at this time and therefore their costs are completely speculative. Also, the feasibility and acceptability of specific sites in the region is not known. There could be substantial controversy and debate over whether additional coal-fired generating resources should be in someone else's backyard. Lastly, extracting coal from surface mines imposes significant impacts on existing land uses and ground water.

The possibility exists that additional, costlier, land reclamation standards could be imposed during the lifetime of these power plants. These kinds of standards would obviously have an impact on the cost of fuel for power plants in the region.

Significant uncertainties always surround the cost and availability of fuels used to fire power plants. Certainly, with respect to coal, the costs of extracting, cleaning, handling and transporting the resource are likely to affect future fuel costs. Further, there is the possibility that additional rail capacity would be needed and affect the cost of delivered coal, but the specifics of transportation bottlenecks and whether they can be overcome easily is beyond the scope of this issue paper. Ultimately, significant uncertainties surround the overall supply and cost of coal for combustion in power plants in the West.

Not unlike all resources included in the Council's plan, coal has its own set of problems and uncertainties. The difficulty in developing a resource portfolio is to appropriately balance the risks and uncertainties of each resource with the others in the portfolio. By diversifying the resource portfolio, the region will be better able to adapt to and manage the risks and uncertainties imposed by the development of all resources.

Coal-fired resources are currently included in the Council's plan as a placeholder for other more environmentally benign resources that are unknown at this time but likely to be available and more cost-effective. But, if loads continue to grow rapidly, decisions regarding coal plants may be required within the next several years because of the long lead times associated with these facilities. This issue paper raises the question as to the appropriateness of this role for coal-fired resources and whether the coal supply curve and scenario described in this paper are reasonable. Everyone in the Northwest hopes to pursue generating resources that have the lowest possible costs, with the greatest certainty and without impacts on the environment. Unfortunately, the panacea resource does not seem to exist, and therefore, the Council's plan must continue to look to a variety of resources that could be used to meet the region's future needs. If loads grow quickly, the plan and the region's electric utility industry must be able to respond.

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